United States of America
Federal Trade Commission

V010003 – Comments Regarding Retail Electricity Competition

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EEI's Response to
The Federal Trade Commission
Notice Requesting Comments on Retail Electricity Competition

I. Introduction

Edison Electric Institute (EEI) is pleased to offer these comments to the Federal Trade Commission (FTC) on retail electricity competition in the states.[1] EEI is the trade association of the nation's investor-owned electric utilities and their affiliates worldwide. In these comments, EEI's will examine state efforts at implementing retail competition within an economic and regulatory framework developed by the leading economic thinkers in the country. Attached to these comments are several monographs addressing retail competition and related topics authored by leading economic and regulatory experts in the field of regulatory restructuring. As the Commission contemplates these questions, these documents could provide a useful resource.

As recent events in the West demonstrate, the success of a state's retail competition program is fundamentally tied to the extent to which it promotes an appropriate balance of supply and demand. A successful program must permit entry by suppliers through the construction of sufficient generation units and use of transmission infrastructure that is able to assure supplies are adequate for market needs. But a market does not work with just the supply hand clapping. Consumers must see appropriate price signals in order to manage demand in relation to price and supply availability. And all electric suppliers must be permitted to engage in long-term contracting and appropriate risk management activities.

II. The Success of Retail Competition Is Measured By Many Factors

One widely discussed measure of a market's success is the number of customers who switch to alternative suppliers. Given that these markets previously had been served only by the utility monopoly, evaluating the emergence of competition with the number of switching customers has superficial appeal. However, there may be many reasons why that customers switch that have little to do with the competitiveness of the market.

For example, some states deliberately set a shopping credit higher than the cost the utility avoided by losing the customer. Given such a subsidy, one would expect to see many customers switch suppliers. Raw numbers can mask the incidents when a customer leaves for a short time during low prices and returns to the utility standard offer service when prices are high. Without an accounting of such gaming behavior, one could conclude that a market is competitive when, in fact, faulty market rules, and not competitiveness, account for the switching. Finally, some states preclude the utility or its affiliates from serving part or all of its former customers. While such rules guarantee high numbers of switching customers, one could hardly conclude with any degree of confidence that switching from state mandated slamming reflects true competitiveness.

While many measures of the success of retail restructuring have been suggested, the ultimate measures are improved customer services at reduced costs as compared to the situation which would have existed in the absence of competition. This can be

[1] Federal Register: March 6, 2001, Volume 66, Number 44, Notices, Page 13536-13539, from the Federal Register Online via GPO Access, wais.access.gpo.gov, DOCID:fr06mr01-105.

measured in a variety of ways, for example, by the amount of new products and services, size of cost reductions, levels of service reliability, and environmental improvement.[2] Several reasonable components of progress are:

- The adequacy of generation supply, as reflected by reserve margins and the amount of new capacity coming onto the market.

- The sufficiency of incentives encouraging investors to risk their capital in the market.

- The ability of demand to respond to price.

- Customer satisfaction, as measured by periodic surveys.

- Customer knowledge about retail market opportunities, procedures, responsibilities and risks, measured by surveys.

- The number of innovations in product offerings.

- The effectiveness of market or regulatory pricing to induce the appropriate response.

III. A Successful Restructuring Program Must Eliminate Barriers to Investment in Generation and Transmission

A. Our Growing Economy Requires Construction of Generation and Transmission Facilities

The booming economy of the past decade has led to a substantial increase in demand for electricity and in the need for new sources of power. In 1990, the North American Electric Reliability Council (NERC) estimated that national demand for power would grow about 1.8 percent annually; in actuality, the rate has been between 2 percent and 3 percent. In its most recent assessment, NERC estimates that more than 10,000 megawatts (MW) of capacity nationally will have to be added *each year* between now and 2008 to keep up with even a 1.8 percent growth rate. However, since 1990, actual capacity additions have been averaging only about 7,000 MW.[3] By the end of the 20th century, the 25 to 30 percent average reserve margins that had prevailed between 1978 and 1992 had dropped significantly — to less than 15 percent, nationwide.

Meanwhile, the Energy Information Administration (EIA), in its Annual Energy Outlook 2001, raised its own projections of electricity demand for the next 20 years because of projected increases in economic growth and the growth in electricity use for a variety of residential and commercial applications. To meet demand growth, EIA

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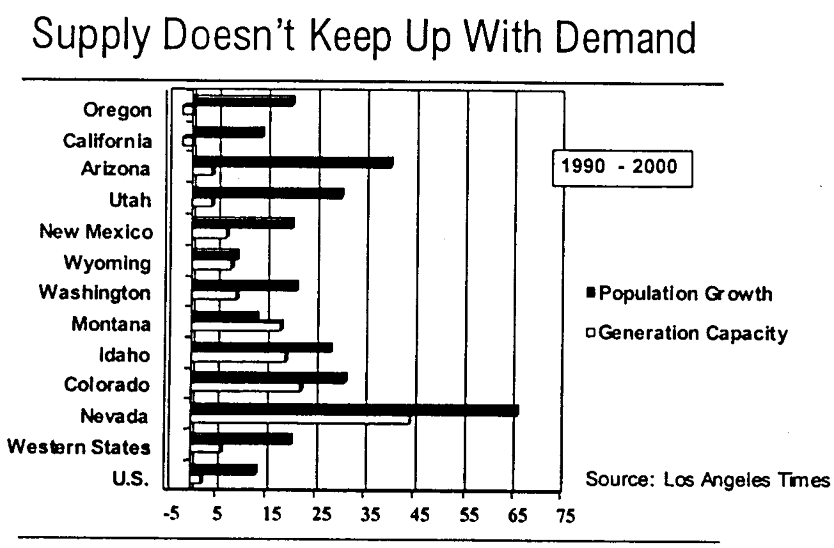
[2] "Progress Toward Competitive Retail Generation Markets: Appropriate and Inappropriate Measures" The Brattle Group, January 2001 Draft.
[3] "Real Competition is the Solution, Not the Problem," Electric Power Supply Association, August 2000.

projects that 1,310 new plants – with a total of 393 gigawatts of capacity – will have to be built by 2020.[4]

Some parts of the country are growing faster, but unfortunately, supply has not kept up with demand. This is particularly true in the West. As this chart demonstrates, Western population grew 20% between 1990 and 2000 while overall generating capacity in the region grew by only 6%. Only one of the 11 Western states, Montana, added enough electric generating capacity to stay ahead of population growth in the 1990s.



Not surprisingly, there is also a substantial unmet need for more transmission capacity. The bottlenecks in California, particularly along Path 15, have been well publicized, but the transmission system is strained in many parts of the nation.

As with generation, transmission growth also has not kept pace with the dramatically increased usage spurred by FERC's open access regulations. Today, more suppliers are trying to put more power on transmission lines that were not designed to be the electrical superhighway. The growing need for the grid to deliver large amounts of power over long distances or to support ever expanding trade has challenged the limits of the transmission system's capacity.

As a result, transmission capacity is becoming an increasingly scarce resource in many parts of the country. USA Today recently noted:

> "in 1995, there were 25,000 transactions where electricity was sold from one region to another. Last year, the number hit 2 million. In a growing number of areas, the transmission lines are carrying all of the power they can."[5]

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[4] "Annual Energy Outlook 2001 With Projections to 2020," Energy Information Administration, DOE/EIA-0383 (2001), December 2000.

[5] Fred Bayles, "California Readies for Blackouts," *USA Today*, August 1, 2000.

The effect of this increased usage has been more congestion in more places. Consumers ultimately may have less access to low-priced power, and reliability may become threatened.

The combination of vastly increased usage together with spare increases in transmission capacity has lead to a substantial decline in relative transmission capacity (measured in terms of MW-miles/Mwpeak demand). From 1989 to 1998, we have seen a 16.2% decline in transmission capacity and project another 12.4% decline during the years ending 2008. NERC projects that the nation will need 30,600 miles of transmission over the next ten years, but only 7,600 miles are planned to be built.

Overlaying the need for new transmission is the fact that as a result of FERC's Order No. 2000, ownership and control of interstate transmission facilities are in the midst of being transferred to newly organized Regional Transmission Organizations (RTOs). FERC has conditionally approved three RTOs and is reviewing several additional applications. Significant ownership, pricing and control issues are now being resolved as these organizations are forming. However, RTOs provide an opportunity to coordinate regional planning and approval for needed transmission enhancements.

B. Federal and State Governments Must Expedite Decisions Regarding Siting of New Generation and Transmission Facilities.

Many of the critical decisions affecting the siting of new generation and transmission facilities are currently within the jurisdiction of the individual states. There are clear differences among the states affecting the ability to construct needed plants. For example, states like Montana, Texas, Pennsylvania and Virginia have facilitated the entry of new generating capacity in recent years.

The ability to site plants has been impeded even when there is an immediate need for extra generation. In San Francisco, the Pacific Gas & Electric Company quit efforts to install four new gas-fired turbines in early August because the approval process would be too lengthy. "We've had ongoing discussions with several state and local agencies that have oversight. As these discussions progressed it became apparent to us that the approval process was not going to coincide with the summer peak season," a company spokesman said.[6]

In altering the structure of the electric utility industry, many states have overlooked the need for a parallel reform of the generation permitting process. Thus, competitive merchant plants are not likely to be owned by a franchised utility serving only a limited area.

The ability to upgrade and build new transmission facilities is also impeded in virtually all parts of the country. Excepting those few instances when state and federal agencies must review projects crossing federal land, the states are responsible for

[6] "PG&E Scuttles Power Station Plans," *Energy Daily*, August 7, 2000.

transmission siting. No federal agency has eminent domain authority as FERC has to site natural gas pipelines. For the most part, states do not engage in regional planning or approval for transmission facilities, even though such facilities are truly interstate in nature.

Obtaining approvals from many state agencies can be quite complex. For example, the Chicago-Apple River transmission line project began in 1996 as a proposal for a 39-mile, 230-kV line that would link facilities in Minnesota and Wisconsin. Because the project is in two states, involves an electric cooperative, would have to cross a river, and involves a national park, reviewing agencies include the Public Service Commission of Wisconsin, the Minnesota Environmental Quality Board, the Rural Utilities Service, the Army Corps of Engineers, the National Park Service, and local governments. Project managers now expect construction of a scaled-down line (161-kV) to begin in 2003 or 2004.

Similarly, just last week, a Connecticut agency denied a request to build an undersea transmission line connecting Long Island with Southern New England.

C. Regulators Need to Design Market Rules That Facilitate Electricity Supply Growth

Generation is a risky business. Power plants require up-front expenditures of hundreds of millions of dollars. An efficient power plant operator will collect enough revenues to recover these costs, plus a profit, over the life of the plant, which could be several decades. Prior to restructuring, the regulated utility monopoly had a reasonable expectation that these costs would be recovered with a fairly low return to reflect a fairly low risk. A competitive market has no comparable certainty.

In approaching restructuring, policy makers need to focus on restructuring's long term goals of facilitating innovation, giving customers more choices and better service, encouraging greater supply and usage efficiency, and lowering costs on average. To achieve these objectives, regulators need to allow market dynamism to run its course. Pre restructuring concepts of utility generation as a low risk business are invalid. While policy makers cannot and should not create a competitive market with the risk profile of the regulated utility, policy makers can and should establish a market structure and competitive rule that reduce the risks and allow a greater return to offset higher risks. Practical experience in competitive energy markets and economic theory offers several suggestions for facilitating the construction of new plants in a competitive market.

First and foremost, policy makers must resist the temptation to re-regulate energy prices when spot markets are volatile and prices spike upwards. Given the wide fluctuations in demand over a single day or, even, a single hour, price volatility must be expected. Moreover, finding ways to avoid this volatility or to hedge against it will be a major driver behind the very innovation should be restructuring. If, as the old saying goes, necessity is the mother of all invention, the need to avoid the California's tremendous price volatility should yield very large progeny.

That said, regulators will need to ensure that high prices reflect genuine scarcity and not a deliberate withholding of supplies by generators with market power. While periods of high prices will be necessary to reward a generator's risk, during the chaotic transition to competitive markets, there may be cause to impose very temporary price caps in response to proven instances of generator withholding.

Regulators should handle the "market power" tool with care: many advocates for various constituencies blithely toss the market power wrench into any market driven outcome they don't especially like. To establish the existence of market power and to quantify its consequences on consumers, regulators must conduct an empirical analysis of the market in question before applying a remedy. Such an analysis could conclude that remedies other than price caps are required or, even, that price caps make the market power worse.

Aside from avoiding the temptation to re-regulate competitive markets, there are proactive ways policy makers can facilitate investment in new generation. For example, regulators can minimize regulatory risks by preventing regulatory micro management and ever changing environmental, business practices, and pricing rules. Also, in establishing market rules, policy makers can establish pricing transparency, while protecting disclosure of confidential proprietary information. Regulators can also promote uniformity in interconnection standards, while still allowing local modifications if necessary for safety and reliability. Government can also fund research and commercialization of new generation technologies, and allow the use of and access to diverse generation fuels to ensure affordable and reliable electricity.

D. Transmission Expansion Requires New Legislative and Regulatory Policies

Upgrading and building new transmission capacity are vital if the country's electricity system is to continue its critical infrastructure role in the American economy and be the "superhighway" of electricity competition. To achieve these goals, EEI has advocated several policy changes at the state and federal level:

- FERC should implement its revised transmission pricing policies broadly to provide rates of return and other appropriate pricing incentives to attract capital to fund needed investments in transmission expansion.

- FERC should provide incentives, such as performance-based rates, that provide opportunities for transmission providers to earn higher returns in exchange for more efficient use of the grid, superior customer service, and productivity gains.

- The Internal Revenue Code should be modified to permit public power entities to participate in RTOs without threatening the tax-exempt status of transmission financing, while privately-owned utilities should be permitted to defer taxes that might otherwise apply if they spin-off or sell transmission facilities to independent businesses that are part of FERC-approved RTOs.

- Federal, state, and local decision makers must cooperate to site transmission that an RTO determines will benefit a region. If cooperation is not possible, FERC should have eminent domain authority to build transmission.

- New mandatory reliability rules must be developed so that all transmission users abide by the same essential reliability requirements. Congress should pass legislation to change NERC into a self-regulating reliability organization under FERC oversight.

- Transmission line project developers should be encouraged to communicate with affected parties at the beginning of the siting process to effectively address local concerns.

E. Congress Should Repeal PUHCA and the Mandatory Purchase Requirements of PURPA

When Congress passed the Public Utility Holding Company Act (PUHCA) in 1935, the Act's significant limitations on utility holding companies and corporate structure were a necessary response to proven financial improprieties over the previous two decades. 66 years later, these same, outmoded restrictions place costly burdens on the ability of the competitive generation markets to develop without serving any compensating public purpose.

Among other problems, PUHCA imposes limits on the business activities of holding companies, acts as a barrier to competition, and deprives consumers of the full range of energy provider services and choices they should have. Moreover, it restricts the flow of capital into energy markets and slows development of generation and transmission capacity. The Act limits the number of new suppliers in electricity markets by prohibiting exempt wholesale generators from selling directly to retail consumers and forms a barrier to regional independent transmission companies. PUHCA also is in direct conflict with the Federal Energy Regulatory Commission (FERC) Order No. 2000.

The agency responsible for administering PUHCA, the Securities and Exchange Commission, has recommended that PUHCA be repealed, with certain consumer protections transferred to the FERC and state regulatory commissions. Congress should oblige.

Another statute that has outlived its usefulness is the Public Utilities Regulatory Policies Act (PURPA) of 1978. During most of its existence, PURPA forced utilities to purchase power they frequently did not need from qualifying generating facilities at prices that were higher than other alternatives. Today, PURPA's nationwide legacy is $8 billion annually in excessive payments to qualifying facilities. Ironically, many of these costs arose in California.

To qualify for beneficial treatment under PURPA, qualifying generators must adhere to specific operating and technical efficiencies. These statutory restrictions have precluded qualifying generators from operating in California, notwithstanding market conditions. Thus, even though California consumers have for years been shelling out tens of billions of dollars in subsidies to support these qualifying facilities, PURPA has created the ridiculous spectacle of forcing power plants not to run at a time the state is experiencing blackouts.

While FERC can, and has, granted temporary, limited waivers of the operating requirements on qualifying facilities, the whole notion of PURPA is alien to the concept of competitive markets. Utilities should be relieved of the legal requirement to purchase the output from favored suppliers, and those suppliers should be relieved of the arbitrary operational requirements. Congress should repeal or reform PURPA.

IV. Demand Response is Critical

A competitive market is created by two groups of interacting economic agents. One group is comprised of sellers, who respond to increasing prices by bringing more goods to the market, and to decreasing prices by bringing less. The other group is comprised of purchasers, who respond to increasing prices by buying less, and to decreasing prices by buying more. Out of the interactions between sellers and purchasers emerge a price and level of output at which the market exactly clears and supply precisely equals demand. This supply/price pairing is known as "equilibrium"; any attempt on the part of suppliers to raise prices above equilibrium will not be sustained because there will be insufficient purchases for the higher levels of supply a rise in prices will elicit.

As this simplified explanation shows, in competitive markets such as generation, an essential ingredient for disciplining high prices from sellers is demand cutbacks from purchasers. Yet, none of the restructured markets has any mechanism for such a vital ingredient of market equilibrium. Worse, all markets have established price capping mechanisms, such as utility provided standard offer service, or provider of last resort services, that guarantee that consumers will **not** experience high prices and **have no price incentive** to alter their demand accordingly. Indeed, when consumers in San Diego experienced pool prices, price caps were re-imposed.

With correct price signals, consumers would be more likely to reduce demand, and various incentives for demand side reduction being adopted by California and other states would have far greater market penetration.[7]

[7] While an increase in prices will result in decreased demand, it is unclear whether the increase approved by the CA will be large enough to raise prices to levels higher than they would alternatively be. Moreover, other factors, such as the state being the monopolist, the continuation of price caps, albeit at higher levels, the credit crunch among QFs, and other market distortions could counteract the demand response of increased rate caps.

There are moves underway to correct the deficiency. Recently Oregon approved a variety of measures to give customers and utilities better ability to manage demand. Portland General Electric (PGE), for example, has an Electricity Exchange Rider that went into effect in July 2000. The rider "allows participating customers an opportunity to voluntarily reduce their electricity usage in exchange for a payment, at times determined by the company." Customers receive 50 percent of the difference between the real-time hourly price and the tariff energy charge.

Between July and November 2000, PGE called 32 events. The six participating customers achieved load reductions of up to 121 MW. PGE paid $1 million to the participating customers.

Georgia Power operates the largest dynamic-pricing program in the United States. About 1,600 of its large industrial and commercial customers (representing about 5,000 MW of load) face hourly prices. In August 1999, when prices exceeded $1,000/MWh, customer response reached 800 MW (roughly a 20 percent load reduction).

Retail customers who can modify their usage in response to high prices help lower the size of price spikes. While most small customers may not choose to manage their own electricity price risk, some large customers might opt for this opportunity. Dynamic pricing allows customers to manage their load requirements in response to real-time electricity prices. While providing the opportunity for financial gain to the customers who choose to participate, these programs can also increase system reliability, mitigate the potential for price spikes during periods of peak demand and supply scarcity, and increase the opportunity for retailers to add value to commodity reselling, as well as indirectly reducing the environmental impacts of electricity production.[8]

Energy is a necessity for all households, and often those who can least afford high prices face the largest bills as a percent of their income and do not have the ability to manage their own price risks. Expanding the Low-Income Home Energy Assistance Program (LIHEAP) and increasing the funding for weatherization and similar efficiency programs can assist low-come households in paying their energy bills and lowering their bills through conservation when prices rise.

V. Electric Suppliers Need Flexibility In Securing Supply Arrangements

As most observers have recognized, one of the major flaws of the California model was the requirement that the utilities, having divested most of their fossil generation, purchase everything from the spot market without the benefit of risk hedges, either from long-term contracts with generators or ownership of power plants. This design shortcoming put utilities in a price squeeze every time the spot wholesale price exceeded the retail price caps. As the incidents of price spikes increased in number, utilities found themselves careening toward insolvency with billions of dollars of costs

[8] "Retail-Load Participation in Competitive Wholesale Electricity Markets" Eric Hirst and Brendan Kirby, January 2001.

that could not be recovered from customers. The lesson of this sad saga cannot be overstated: Electric suppliers must be permitted to utilize risk management tools, including long-term contracts, other hedging tools and, if necessary, ownership of generation. Moreover, mandatory divestiture of generation is not likely to be a good idea.

A. States Should Allow Hedging and Risk Management for Provider of Last Resort Obligations

A common feature of restructuring is that the incumbent distribution company typically has the obligation to provide highly regulated standard offer service, despite the fact that they have relinquished the cost-recovery protection afforded by traditional service franchises and that some price volatility in wholesale markets is a fact of life. These residual obligations can represent large liabilities for the distribution company and entails a high degree of risk.

In today's emerging competitive generation markets, various hedging options are an important risk management tool. These include long-term contracts with generators that lock in a specific price and the actual ownership of generation tied to fixed-priced fuel contracts. As electricity markets become more liquid, other hedging tools familiar in commodities and fuel markets are emerging. These include options, forward contracts, and futures.

Effective hedging requires regulatory certainty to guard against post-hoc disallowances. At first, California utilities were prohibited from using risk management techniques. Once risk management techniques were permissible, utilities were concerned that any money saved by risk management would be passed onto customers, while any risk management that loses money will be borne by shareholders. With such lose-lose options, a utility's incentives to hedge risks are minimal.

B. Rate Caps and Rate Freezes Should Only Be Temporary As Part Of A Transition.

Almost all the states that are restructuring for retail competition have included a transitional rate freeze applied to the standard offer service (SOS). Alternatively, utilities must stand ready to be a provider of last resort (POLR) at capped rates. Often, the residual transmission and distribution utilities have accepted these obligations almost reflexively: after all, they are still utilities with obligations to serve. As markets have evolved, two problems have arisen.

First, in effect, utilities are in the position of providing valuable insurance without compensation for the premium that should accompany this risk. As witnessed over the past three summers in various regional markets, wholesale electric spot prices are extraordinarily volatile and can be extremely high for short periods. In such volatility, the unhindered ability of retail customers to return to the utility at capped prices is a valuable option. Under current rate practices, retail customers do not pay anything for this option.

Moreover, were the utility to take out an insurance policy covering their risk exposure, the only time they could recover the costs of this service is in volumetric rates when the customer takes the energy.

To ensure cost recovery, utilities in the role of providing SOS and POLR service should receive from customers a monthly payment for the costs they incur to have the power should it be called upon. This could be in the form of standby or back-up charges.

Second, the availability of default utility services at capped rates, especially if accompanied by a rate cut, has resulted in a near impossible hurdle for competitive suppliers to beat. As a result, the movement toward competition is stillborn before restructuring has left the station.

C. Supply Sufficiency Requires Credit and Liquidity Adequacy

One important lesson from the California experience is the extent to which a massive credit crunch caused by the retail rate cap has contributed to the withdrawal of needed electric supplies from the market. California's two major distribution utilities have been unable to pay billions of dollars to their suppliers because the distribution utilities have been selling electricity to retail customers at rates far below their cost of purchased power.

Many of non-utility suppliers, particularly, qualifying facilities, have in turn been unable to pay their suppliers and have withdrawn from producing and selling electricity. Recent information from the California Independent System Operator estimate that this has caused a 3,000 MW reduction in supply. There has also been a tremendous amount of litigation between suppliers, the distribution utilities and the California ISO in the court and at FERC addressing credit and payment issues. Nobody knows the impact of the credit crunch, the trail of non-payment, the added financing costs and the added risks to sellers on the amount of generation kept off the markets, the liquidity of the market, and increased generation costs.

Thus, states must adapt their policies to the liquidity needs of newly competitive wholesale electric markets. This is as true for states that retain traditional regulation as for those that engage in retail restructuring.

D. States Should Consider Utilizing Performance-Based Regulation for Distribution Services.

Performance-based regulation (PBR) could streamline regulatory processes, leading to administrative cost savings for utilities and their customers. Industry experience suggests that there are three fundamental requirements for the long-term success of PBR plans, as follows: (1) Risk/Return Symmetry - PBR plans must maintain a balance between expected rewards (returns) and expected penalties (risk). This is critical to ensure that utilities can continue to attract private investor capital on reasonable terms, and to avoid incentives to dis-invest in the regulated sector; (2) Broad Incentives -

PBR incentives should apply broadly to the utility (e.g., to reduce unit costs), not narrowly (e.g., to invest in preferred DSM programs) and should reflect those attributes which customers value. This is essential to avoid sub-optimization (e.g, maximizing DSM investment, but raising total system cost). It also is essential to induce utilities to act like competitive firms; that is, to take responsibility for managing their own resources, as opposed to being micro-managed by utility commissions via highly targeted incentives; (3) Regulatory Commitment - Regulatory authorities need to honor PBR plans over the term of their operation. This is essential if utilities are to believe in the PBR deal; that is, if they are to stop managing the regulatory relationship, and concentrate on managing the business.

E. State Regulations Over Affiliate Transactions Should Guard Against Harmful Actions While Preserving Economies of Scope

In competitive market, utilities should not give preferences or cross-subsidizes to competitive affiliates. In Order No. 2000, FERC substantially addressed these concerns in the development of independent Regional Transmission Organizations (RTO). Order No. 2000 ensures utilities cannot a abuse their control of transmission facilities to favor their own services. It also provides that a utility may not control more than 5 percent of an RTO for over five years.

That state rules are necessary is not in doubt. Regulations must ensure that utility ratepayers do not cross-subsidize the non-utility affiliate. This could result if the utility pays too much for services provided by an affiliate, or if the utility provides services without being paid at least the added costs of providing the services. Regulations also must guard against the utility giving preferential utility services to affiliates, or of tying the provision of utility services on the purchase of the affiliate's services.

However, in many states there has been considerable disagreement over how stringent rules should be separating the utility and it unregulated competitive affiliates to achieve these results. In many cases utility competitors sought extremely burdensome rules in order to improve their own competitive position, even when such rules would adversely affect consumers.

Since any restructuring is bound to disrupt preexisting arrangements that were beneficial, policy makers must strike a delicate balance affecting the necessary separation and sacrificing preexisting cost saving practices. Some states have struck the wrong balance. California's decision to require all purchases to be on a short-term spot market was largely a response to affiliate concerns, as was that state's development of extremely detailed restrictions on sharing of non-utility facilities and services. In retrospect, these were the wrong choices.

The sharing of resources by a utility with its affiliates can lower utility rates and competitive market prices. Regulators should encourage such sharing while guarding against cross-subsidization, which arises when a utility shares resources with its non-utility affiliate at a price that raises the cost of serving utility customers. When a utility provides services to its affiliates, any price between the utility's incremental cost and the stand-alone cost of providing the service is subsidy free. When a utility makes a one-time purchase of goods or services from its affiliate, any price equal to or lower than the market price or the utility's incremental cost of providing the good itself is subsidy free for one-time purchases. For longer-term purchases, the pricing needs to reflect benefits from long-term commercial arrangements. There must be one exception to these transfer pricing rules: for utility sales of utility services to its affiliates, the price must be at regulated rates and identical terms of service that apply to non affiliates.

Note that this problem is markedly different from the situation, described above, where price caps eliminate the ability of competitors to compete against price-capped SOS and POLR services. Unlike the SOS and POLR service offerings, prices for competitive energy are not capped when a utility shares economies of scope with an affiliate. Any efficient supplier will be able to apply their own efficiencies to compete against a utility's affiliate, but nobody will be able to compete against a utility's SOS service when market prices are higher than the cap.

Regulators can apply accounting controls to protect against cross-subsidization. Well known accounting methods such as cost allocation guidelines and transfer pricing rules, provide sufficient regulatory oversight of affiliate transactions. These practices form the basis of FERC's Uniform System of Accounts, which allows for review of allocation assignments. In spring 2000, for example, the Wisconsin commission stated in its affiliate rules order that "allocation of costs between utility activities and nonutility activities...minimizes utility service costs to ratepayers and reduces the risk of undue subsidies to the nonutility activity."[9]

Utilities also follow Generally Accepted Accounting Principles for the preparation and filing of financial statements. Finally, many utilities have Cost Allocation Manuals to set forth policies and procedures for allocating costs for services and products transferred between regulated and non-regulated businesses.

VI. With Deference to Investments Already Made, States Should Adopt Uniform Business Practices

All utilities in states that have restructured developed business practices to give marketers and delivery companies a single set of procedures for determining who gets what customer information and billing data, in what format, and how quickly. However, business practices vary not only from state-to-state, but sometimes within a single state. This lack of uniformity can increase transaction costs for retail marketers, electric delivery companies, and customers.

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[9] Public Service Commission of Wisconsin, Docket No. 05-BU-101, Investigation On the Commission's Own Motion Into Utility Business Activities and Into Transactions and Relationships of Utilities and Their Affiliates During the Transition of Restructured Electric and Gas Industries; Potential Effects of Increased Competition on Markets and Consumers, April 26, 2000, at 4.

Uniform business practices can lower barriers to market entry, encourage new product lines, reduce utility distribution company system costs to accommodate retail access, and enable customers to benefit from more price and product benefits. While the goal is to have uniform business practices used as widely as practicable, states that have already been early adopters and should not unnecessarily be required to abandon the systems that are already in place and being paid for by consumers.

EEI is proud that we have spearheaded an energy industry group that includes utilities, energy suppliers, regulators, vendors, consumer advocates and trade organizations to published a two volume report on Uniform Business Practices (UBP) for retail energy markets. Volume I of the report recommends business practices for customer information, customer enrollment & switching, billing & payment processing, load profiling, supplier licensing, market participant interaction, disputes between the utility and the supplier, and customer inquiries. Volume II comprehensively addresses unbundled electricity metering.

EEI along with the Coalition for Uniform Business Rules, the Electric Power Supply Association, and the National Association of Energy Marketers Association sponsored this effort. To obtain a copy of the report or to learn more about the UBP process, visit www.ubpnet.org.

VI. Conclusion

EEI respectfully appreciates the opportunity to submit these comments. We believe that the success of a state's retail competition program can be measured in a variety of ways, for example, by the amount of new products and services, size of cost reductions, levels of service reliability, and environmental improvement. Several reasonable components of progress are:

- The adequacy of generation supply, as reflected by reserve margins and the amount of new capacity coming onto the market.
- The sufficiency of incentives encouraging investors to risk their capital in the market.
- The ability of demand to respond to price.
- Customer satisfaction, as measured by periodic surveys.
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- The number of innovations in product offerings.
- The effectiveness of market or regulatory pricing to induce the appropriate response.

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Respectfully submitted,

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List of Attachments

1. "Retail-Load Participation in Competitive Wholesale Electricity Markets," Eric Hirst and Brendan Kirby, January 2001.

2. "States Set Rules of the Road for Electricity Competition: A Summary of State Standards of Conduct Governing Competition in New Electricity Markets," Edison Electric Institute, January 2001.

3. "Fuel Diversity Key to Affordable and Reliable Electricity," Edison Electric Institute.

4. "The Effect of Price on Residential Customer Choice in Competitive Retail Energy Markets: Evidence from Specific Markets to Date," Kenneth Train and Anne Selting, National Economic Research Associates, March 2000.

5. "Residual Obligations Following Electric Utility Restructuring," Frank C. Graves and James A. Reed, Jr., The Brattle Group, March 2000.

6. "Open Entry, Choice, and the Risks of Short-Circuiting the Competitive Process," Kenneth Gordon and Wayne P. Olson, National Economic Research Associates, March 2000.

7. "Deregulation: Micromanaging the Entry and Survival of Competitors," Alfred E. Kahn, National Economic Research Associates, February 1998.

8. "Generation and Transmission Adequacy in A Restructuring U.S. Electric Industry," Eric Hirst, Brendan Kirby, and Stan Hadley, June 1999.

For copies of the attachments, please contact Louis Harris at 202-508-5524 or Elizabeth Stipnieks at 202-508-5566.